Attachment 4

The Projected Impacts of NO_x Emissions Reductions on Electricity Prices in Indiana

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Abstract

This paper examines the impact of various nitrogen oxides (NO_x) emission control scenarios on the projected prices of electricity in the state of Indiana. The scenarios represent different methods for reducing NO_x emissions levels to either 0.15 or 0.25 lbs/mmBtu. The analyses were performed using a traditional regulation forecasting model that equilibrates between price and demand. Thus, the effects of price changes on demand levels were captured. Price impacts are presented at an overall average level as well as by customer class. The impacts of various assumptions made in the selection of the scenarios are analyzed.

1. Background

Nitrogen oxides (NO_x) is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. These oxides of nitrogen react with volatile organic compounds in the presence of heat and sunlight to form ozone. In the upper atmosphere, ozone occurs naturally and shields the earth from the sun's harmful ultraviolet rays. However, closer to the ground ozone poses significant risk to human and plant health. Exposure to ozone irritates human lungs, reducing lung function and exacerbating respiratory diseases such as asthma. Ground-level ozone interferes with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised. It is also a major component of urban smog [1].

While NO_x emissions rates vary from plant to plant according to the design of the plant and the characteristics of the fuel, an uncontrolled emission rate of 1.0 lbs/mmBtu is typical for coal-fired generators. The Clean Air Act Amendments of 1990 called for reductions in two stages. The first stage, Phase I, went into effect in 1996 and required Group 1 boilers (dry bottom boilers and tangentially fired boilers) to reduce NO_x emissions rates to 0.45 to 0.50 lbs/mmBtu. Phase II took effect in 2000 and further limited Group 1 boiler emissions rates to 0.40 to 0.46 lbs/mmBtu. Phase II also placed limits on Group 2 boilers (other boiler types) to 0.68 to 0.86 lbs/mmBtu [2]. In 1998, the Environmental Protection Agency proposed further reductions to 0.15 lbs/mmBtu as of May 2003.

The compliance options available to fossil generators fall into three distinct categories: emission control technologies, fuel switching, and the use of NO_x emission allowances. The proposed plans used in the development of these scenarios did not include the use of allowances. There are two main categories of emission control technologies, combustion control and post-combustion technologies. Low NO_x burners, which work at the combustion stage, were installed in many generating units to meet compliance with the Clean Air Act Amendments of 1990. Other forms of combustion control technologies include flue gas recirculation, steam or water injection, and staged combustion. Post-combustion control is done using either catalytic or non-catalytic reduction. The characteristics of some of the NO_x control compliance options are illustrated in Table 1.

In Selective Catalytic Reduction (SCR) systems, ammonia vapor is used as the reducing agent and is injected into the flue gas stream downstream of the boiler. The mixture passes over a catalyst, reducing the NO_x to nitrogen and water. SCR is one of the few technologies capable of removing high levels (80% or more) of NO_x from the flue gas of coal-fired generators commonly used in the U.S. utility industry.

In Selective Non-Catalytic Reduction (SNCR) systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. Emissions of NO_x can be reduced by 30% for large boilers to 50% for smaller boilers. The NO_x and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. Both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_x reductions.

Low NO_x burners reduce NO_x formation in the combustion stage by reducing flame temperature and local oxygen concentrations. This is accomplished by controlling the fuel and air mixture to alter the size and shape of the flame.

Fuel switching involves replacing coal or oil as a source of fuel with natural gas to lower NO_x emissions. Fuel switching can involve a complete switch to all natural gas fuel or to partial fuel switching. Partial fuel switching consists of two main options: seasonal switching and natural gas reburn. Seasonal switching involves using natural gas as the fuel source during the summer, which is the primary ozone season. Natural gas reburn involves co-firing a small amount of natural gas (10-20%) with the other fuel source. The costs associated with fuel switching vary greatly depending on the boiler size and design as well as access to natural gas. It usually results in higher fuel costs.

	SCR	SNCR	Low NO_x Burners	Switching to Natural Gas
removal efficiency	high 80%	low to medium 30-50%	medium 40-60%	variable 25-75%
capital cost	high	low	low	varies greatly

	50-90 $/kW	12-20 $/kW	10-30 $/kW	
O&M/fuel cost	high fixed low variable	low fixed high variable	low fixed low variable	high fuel

Table 1 Characteristics of NO_x Control Strategies [3]

Due to its large reserves of Illinois Basin coal, Indiana depends quite heavily on coal as a fuel source for electricity generation. Over 90% of the electric power generating capacity in the state is coal-fired and over 98% of the electricity generated there is derived from coal. As a result of this reliance on coal, Indiana ranks second in the United States in the amount of NO_x emitted annually [4]. Therefore, NO_x emissions reduction regulations will significantly affect Indiana.

The analyses were performed for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Cinergy, and Southern Indiana Gas & Electric Company) and three major not-for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association)that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined.

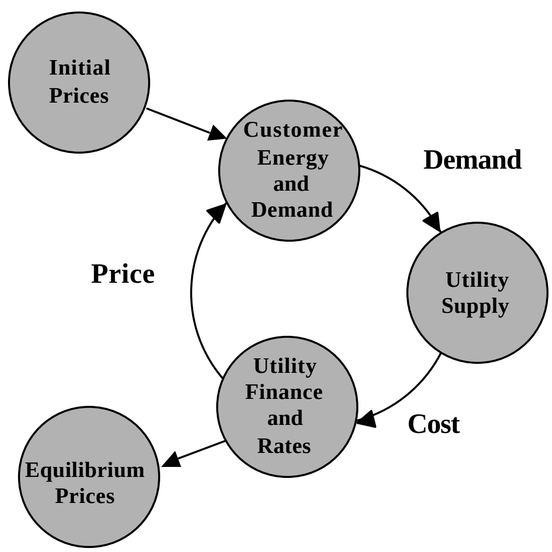
2. Methodology

To determine the impacts on prices of various levels of NO_x emissions restrictions, numerous scenarios were analyzed using a traditional regulation forecasting model developed by the State Utility Forecasting Group (SUFG) [5]. This model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups -- residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out-of-pocket operating costs.

The fuel price and economic activity forecasts that form the primary drivers of these models were not changed from one scenario to another to maintain consistency in the analyses. The other major model driver, the price of electricity, varies according to the results of the scenario. Therefore, any changes in customer demand from one scenario to another result entirely from the NO_x reduction requirements.

Using an initial set of electricity prices for each utility, a forecast of customer demands is developed. These demands are then sent through a generation dispatch model to determine the operating costs associated with meeting the demands. The operating costs and demands are sent to a utility finance and rates model that determines a new set of electricity prices for each utility. These new prices are sent to the energy and demand model and a new iteration begins. The process is repeated until an equilibrium state is reached where prices and demands do not vary from one iteration to the next for each year of the analyses. Thus, the model includes a feedback mechanism that equilibrates energy and demand simultaneously with electric rates (Figure 1).

Figure 1 Cost-Price-Demand Feedback Loop



In the later years of the analyses, new generating capacity is needed for the utilities to adequately meet the load. This is accomplished through another iterative process with the costs associated with acquiring this capacity (either through purchases or construction) impacting the rates accordingly. Since the demand levels in each scenario differ due to the price impacts, the amount of new capacity changes also. However, the criteria for acquiring new capacity are held constant to ensure consistency between scenarios.

NO_x control technologies will affect the price of electricity in several ways. In this modeling system, the capital cost of equipment is captured in the rates and finance model, using a traditional regulated rate of return. The operating cost impacts are captured in the generation dispatch model. These impacts include changes in fuel costs resulting from changes in overall plant efficiency, increased maintenance costs, and changes to generation unit availability, for both NO_x reduction equipment installation and maintenance.

3. NO_x Control Scenarios

The Indiana Department of Environmental Management (IDEM) provided SUFG with five scenarios describing compliance strategies for reduction of NO_x emissions from coal-fired electric utility generation plants. All of these scenarios involve retrofit of control devices to reduce NO_x emissions during the "ozone season" of May through September. Four of the scenarios pertain to a system average emission rate of 0.25 lbs/mmBtu and the fifth pertains to a system average emission rate of 0.15 lbs/mmBtu. This is in contrast to an emission rate 0.40 to 0.46 lbs/mmBtu, depending on boiler type, allowed for Group 1 coal-fired generation plants under Title IV of the 1990 Clean Air Act Amendments. The four 0.25 lbs/mmBtu scenarios differ somewhat in cost estimates depending upon the source of the estimates and somewhat in the control strategies employed. In the scenarios the common control strategies involve retrofit of SNCR, SCR, and in some cases, combustion control modifications. The key operational and cost attributes assumed by IDEM for the SNCR and SCR retrofit controls are listed in Table 2.

	SNCR	SCR
NO_x Removal (Percent)	30.0	80.0
Installation Cost ($/kW)	16.0-18.0	85.0-135.0
Fixed O&M Cost ($/kW-Yr)	0.15-0.45	0.45
Variable O&M Cost ($/MWh)	0.8-1.0	0.5-0.8
Heat Rate Increase (Percent)	0.0	0.25
Net Capacity Decrease (Percent)	0.0	0.67
Installation Outage (Days)	14	42-70

Table 2 Retrofit Parameters

The primary differences between scenarios 1 through 4 are the sources for baseline emissions and the efficiency and costs of the technology choices.

Scenario #1 Both baseline emission rates and technology efficiency and costs derived from EPA. Allowable emissions 0.25 lbs/mmBtu.

Scenario #2 Baseline emission rates derived from EPA. Technology efficiency and costs derived from a combination of utility sources and published information. Allowable emissions 0.25 lbs/mmBtu.

Scenario #3 Both baseline emission rates and technology efficiency and costs derived from a combination of utility sources and published information. Allowable emissions 0.25 lbs/mmBtu.

Scenario #4 Same as Scenario #3 with a small safety margin built in.

Scenario #5 Same as Scenario #3 with allowable emissions lowered to 0.15 lbs/mmBtu.

Table 3 lists the amount of capacity affected and the installation costs for each of the IDEM scenarios.

Scenario	Capacity Affected (MW)		Installation Costs (million 1998$)
	SNCR	SCR	
#1	2018	6966	571.2
#2	1864	7455	775.2
#3	1965	8800	916.7
#4	1078	9712	999.7
#5	1688	14076	1419.3

Table 3 Capacity Affected and Installation Costs

In addition to the IDEM scenario assumptions, SUFG made further assumptions in order to perform this analysis using SUFG's traditional (or regulated) modeling structure. These assumptions pertain to future capital costs for retrofit control equipment, expenditure streams for retrofit equipment installation, and the timing of retrofit installations. SUFG feels these assumptions are reasonable, but also recognizes that they should be subject to further refinement in subsequent analyses, as further information becomes available.

SUFG has assumed that capital costs for NO_x retrofit control equipment will escalate at an annual rate of 2.5% per year from the 1998 dollar base year estimates provided by IDEM. This assumption applies to all control technologies including SNCR and SCR devices as well as combustion modifications. While this escalation rate assumption is open to debate, it is consistent with the assumptions SUFG employed in preparing the 1999 SUFG report *Indiana Electricity Projections: The 1999 Forecast*, which is used as a base case in estimation of the additional costs to ratepayers of further NO_x emission reductions.

SUFG has assumed that NO_x retrofit control equipment for all affected generation units will be installed over a 15-month period for all retrofit options including SNCR, SCR, and combustion control. SUFG has further assumed that the stream of expenditures for such retrofit is evenly divided across this 15-month period. Since the SUFG model is an annual model, SUFG has allocated the NO_x control retrofit costs to specific years based upon the assumed on-line date of the control equipment. Capital costs are escalated from the 1998 dollar base year to the middle of the 15 month construction period and then allocated to specific years. For example, if a control device is assumed to be on-line in the spring of 2003, capital cost are escalated from 1998 dollars to mid-July 2002 dollars and then allocated to 2002 expenditures (80 percent of the total) and 2003 expenditures (20 percent of the total). The same procedure is used for fall installations, with capital escalation through mid-February of the on-line year and capital cost allocations of 40 percent (prior year) and 60 percent (on-line year). Fixed operations and maintenance costs are assumed to be incurred immediately following the installation of a control device even if the control is installed prior to May 2003 compliance requirement date.

The 15-month installation period used in these analyses does not represent the total time needed for planning, design and engineering. These processes take a considerable amount of time before the actual physical construction begins. Likewise, the 15-month time period does not represent the time that the generating unit must be taken out of service for the installation process. The downtime used in these analyses were 2 weeks for SNCR and 6 to 10 weeks for SCR installations.

Since installation schedules for NO_x controls were unavailable, SUFG assigned installation dates for all retrofit controls. The procedure used to assign on-line dates is somewhat arbitrary and should be refined in future analysis. SUFG assigned on-line dates by attempting to minimize the capacity off-line for retrofits and delaying retrofits until required for compliance on an individual utility basis. For example, if a utility is required to retrofit two large coal units, the units were assigned retrofit dates of Fall 2002 and Spring 2003; three large units were assigned retrofit dates of Spring 2002, Fall 2002, and Spring 2003 and so forth. A more reasonable allocation of retrofit dates would explicitly incorporate the utilities maintenance schedules and attempt to overlay final installation with major maintenance periods as well as attempt to coordinate installation outages across utilities where possible.

The NO_x emission control strategies analyzed here were developed while allowing averaging of NO_x emissions reductions among an individual utility's generating units. This allows a utility to over-control NO_x emissions from specific generation units while exceeding emissions rates for other generation units as long as the system-wide reduction in NO_x emissions is adequate to meet the required emissions reduction. By allowing a utility to average emissions across system generation, the utility is able to control emissions in a more cost effective manner if the marginal cost (dollars per ton removed) of installing and operating emissions controls varies between generating units. To minimize compliance costs, the utility would choose the most cost effective mix of control measures and over-control to meet the target emissions reduction.

Similar cost savings strategies may be possible across utilities, where one utility may have an emissions control marginal cost advantage compared to another utility. In this situation the minimum cost strategy would require emissions averaging across utilities or regions. Typically, this would be facilitated by allowing utilities to trade emission allowances (the right to emit a ton of NO_x) through a market mechanism where emission allowances are bought and sold. This market would provide a means whereby those utilities with a relative advantage in the marginal cost of emission controls could over-control emissions and sell their resultant emission allowances to those utilities with higher NO_x control costs. The net result of emissions trading would be an overall reduced electricity price from the price that occurs without such trading.

While these analyses capture the price effects of retrofit outages, they do not address the question of whether the reliability of the system will be impaired. The East Central Area Reliability Coordination Agreement (ECAR) “strongly endorses maintaining a 42 month construction window for retrofit.” [6].

4. Results

SUFG’s projections of future electricity rates for two of the five NO_x emission control scenarios are compared with a base case from SUFG’s 1999 report *Indiana Electricity Projections: The 1999 Forecast* in Figure 2. Scenarios #1 through #4 have prices within one percent of each other and are indistinguishable when graphed. Therefore, Scenario #3 is the only one shown. The base case was constructed assuming no addition NO_x emission control beyond that required by the 1990 CAAA, so the IDEM scenarios represent incremental changes to the base case. The rate projections in Figure 2 are an energy-weighted average for the residential, commercial, and industrial sectors for the five Indiana investor-owned utilities. The figure illustrates that average retail rates would be expected to increase 4 to 6 percent if NO_x emissions were reduced to 0.25 lbs/mmBtu and 6 to 8 percent if NO_x emissions were reduced to 0.15 lbs/mmBtu.

Figure 2 Comparison of Rates by Allowable Emissions

There is very little difference between the first four scenarios. The single most important factor affecting prices is the allowed emissions rate, as can be seen from the difference between the base trajectory and that for the 0.25 lbs/mmBtu scenarios. Likewise, the trajectory for Scenario #5 is visibly higher than the others. From this, it can be concluded that the choice of technology and efficiency values, as well as the choice of base emission rates, has little impact.

The effect on the individual rate classes is similar to the average but differs somewhat due to cost-of-service allocation of capital recovery and fixed operating costs. The differences across customer classes for IDEM Scenario #3 and Scenario #5 for a representative year are presented in Table 4.

	Base Scenario (¢/kWh)	Scenario #3		Scenario #5	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.35	6.59	+3.8 %	6.84	+7.8 %
Commercial	5.26	5.46	+3.9 %	5.65	+7.4 %
Industrial	3.71	3.85	+3.6 %	3.95	+6.4 %
Average	4.88	5.07	+3.8 %	5.24	+7.3 %

Table 4 Rate Comparisons by Sector in 2005

The difference between SUFG's base case and Scenario #5 is about 0.35 ¢/kWh. Roughly 0.05 cents or 1/7 of the increase is due to increased out-of-pocket operating costs incurred during the May to September ozone season and the remainder of the increase, about 0.30 ¢/kWh is due to recovery of equipment installation costs and fixed operating costs.

It is important to note that the rates reported here are annual rates that tend to hide the differences between the ozone season and the non-ozone season. During the ozone season, additional operational costs are incurred that are associated with the NO_x removal process. These costs are not incurred during the non-ozone season.

5. Summary and Conclusions

This paper presented the projected impacts of NO_x emissions reductions on Indiana electricity prices. Scenario analyses were performed using the SUFG traditional regulation modeling system. These scenarios depict various combinations of control technologies, such as SCR and SNCR, and two different levels of allowable emissions.

The results of these scenarios indicate that electricity prices can be expected to increase due to NO_x emissions reductions. If NO_x emissions are reduced to 0.25 lbs/mmBtu, retail rates are projected to be from 3 to 6 percent higher that those with unchanged emissions levels. A reduction to 0.15 lbs/mmBtu results in rate increases of 6 to 8 percent. The efficiency levels and costs associated with the control technologies vary according to the source of the information. Similarly, the base level of emissions used to determine the allowable amount of emissions in the future varies according to the source of the information. However, these choices have little effect when compared to the choice of the level of impact reductions. Finally, the increase in electricity rates resulting from NO_x emissions reductions is felt by all three customer classes, with the increase to residential rates being slightly greater (and the increase to industrial rates being slightly lower) than the increase to commercial rates.

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